APPROACHES TO CAPTIVE POWER REGULATION

SUPPORT TO THE RWANDA UTILITIES REGULATORY AUTHORITY UNDER THE RWANDA ENERGY REGULATORY PARTNERSHIP

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List of Acronyms or Abbreviations

CPUC - California Public Utilities Commission

DER - Distributed Energy Resources

DG - Distributed Generation

DL - Distribution Licensee

EPRA - Energy & Petroleum Regulatory Agency of Kenya

EPSRA - Electric Power Sector Reform Act

ERA - Electricity Regulatory Authority [of Uganda]

FIT - Feed-in-Tariff

IPP - Independent Power Producer

kWhs - Kilowatt hours

kWs - Kilowatts

LES - Lincoln Electric System

NARUC - National Association of Regulatory Utility Commissioners

NEM - Net energy metering

NERC - Nigerian Electricity Regulatory Commission

PPA - Power Purchase Agreement

PUCs - Public Utility Commissions

PV - Photovoltaic

RE - Renewable Energy

RTO - Regional Transmission Organization

RURA - Rwanda Utilities Regulatory Authority

USAID - United States Agency for International Development

VNEM - Virtual Net Metering

VOS - Value of solar

1. Introduction & Context

With the support of the United States Agency for International Development (USAID) and Power Africa, the National Association of Regulatory Utility Commissioners (NARUC) conducted a workshop in February 2020 on grid integration of renewable energy (RE) in Rwanda, which focused on captive power regulation. Captive power is a term used to describe behind-the-meter electricity generation used explicitly or mainly for self-consumption. Captive power suppliers are historically large industries where quality and continuity of supply are of utmost importance, but recently there is a shift to smaller solar power systems in the form of DERs in order to take advantage of decreasing cost for solar power systems which are outcompeting grid tariffs in some cases. Similarly, Rwanda expects a widespread application of solar DERs into the system.

The activity was designed to support the Rwanda Utilities Regulatory Authority's (RURA) efforts to establish a regulatory framework for customers generating and consuming electricity on-site by deploying captive power infrastructure. The discussion expanded to include other policies related to net metering and distributed generation (DG) and the larger topical umbrella of distributed energy resources (DER) as they relate to electricity generation solutions for a wide number of consumers in Rwanda. These discussions have consequently formed the basis of this paper, which is to provide RURA with a reference tool and examples of strategies used to regulate captive power. Through development of their own mechanism to regulate captive power/DERs, Rwanda will increase transparency and thus predictability of treatment of captive power/DERs in the country. Increased transparently will assist in creating an enabling environment for private sector investment in captive power/DER generation sources.

Widespread use of captive power in Rwanda in general, and DERs in particular, will pose implementation challenges for a number of technical and regulatory reasons. As such, Rwanda's interest in captive power and DER implementation will require a robust national regulatory framework to govern operations and minimize implementation and operational challenges. The decentralized supply chain made up of various DER systems at the distribution level may be perceived as a threat to distribution companies' (utilities') financial viability and status-quo network operations, which are generally not designed for high level intermittencies and two-way flow of power.[1]

Regulators must assess these foreseeable challenges and address them in a comprehensive regulatory framework designed to address common implementation and operational challenges as exhibited in other countries that have already deployed considerable volumes of DER and captive power technologies. Gleaning lessons learned from their experiences will inform RURA's approach, which will contribute to a well-formulated regulatory framework for growing DER infrastructure.

In the U.S. and elsewhere, regulators have acknowledged that the future of the grid will continue to accommodate widespread expansion of DER. As such, many regulators are developing policy roadmaps to manage potential risk and seize potential opportunities present for the entire electricity industry. This report emphasizes the need for Rwanda to start developing an adoption plan for DERs in order to capture their long-term benefits early on and provide value for all customers, as well as spearhead and lead the DER movement to lead as a worldwide example of a country exhibiting successful, pioneering DER adoption and regulation.

This report, prepared by NARUC in concurrence with its ongoing assistance to RURA on captive power issues, proposes that RURA develop a longer vision on captive power and prepare a strategy for DER

[1] On the other hand, it is important to note that advanced control capabilities of DERs offer potential opportunities for improving electric system reliability when applied in a planned and well-thought-out manner.

implementation that both encompasses captive power and embraces various advantageous DER technologies to ensure greater power system efficacy. Coupled with recent technological advancements and development of innovative business models, it is envisaged that RE systems and RE energy storage technologies will expand beyond captive power systems and continue to transform power grid operations.

Designed as a regulatory tool and reference for RURA, this report compares and contrasts respective captive power regulations in place in the U.S., Uganda, Nigeria, Kenya, and Turkey. These case studies provide examples of how RURA can prepare a regulatory framework to appropriately serve Rwanda's immediate need to regulate captive power, addressing foreseeable pitfalls and challenges by ensuring relevant regulatory provisions beforehand. Furthermore, the U.S. case study provides an overview of how rooftop solar panels led to net metering regulations in the U.S., and how these developments 1) evolved into initiatives to integrate more DER into the grid, and 2) prompted regulators and government agencies to prepare for the future of heterogeneous and evolving electricity grids.

As another example, the case study on Uganda examines how DERs are regulated as part of a broader isolated-grid system approach and provides a governmental approach to regulating DERs in a context more similar to that of Rwanda. The examination of Nigeria's captive power regulation illustrates how having a simple and explicit captive power regulation can provide clarity to interested consumers, operators, and developers alike, while the Kenya case study examines Kenya's multi-regulation approach, regulating captive power systems through provisions included in various peripheral electricity regulations.

Lastly, the final case study examines Turkey's approach to regulating captive power and DERs given the changing conditions of the electricity system and the changing market design in a time span of 30 years. These case studies culminate in a set of final recommendations for RURA to consider moving forward with crucial initial stages in composing and implementing Rwanda's captive power regulation.

2. Defining Captive Power & Distributed Energy Resources

A captive power plant is an electricity generation plant that supplies power wholly or primarily to one user (or several users) rather than to a utility; captive power definitions generally include a percentage of self-consumption. There is no "correct" value for the self-consumption requirement; it depends on a number of factors such as the system generation adequacy level, network capacity limits, or other policy considerations. The self-consumption requirement can range from 100% of the generation to much lower levels. It is also possible to adjust this requirement during the process.
For example, when the system *needs* additional generation, the regulator can allow a higher percentage of energy from captive power generators to be sold to the system; when there is *enough* energy in the system, the captive power sales can be limited back to their original percentage of generation. As pricing options are to be considered in the regulation, excess energy can be bought at a regulated price (sometimes referred to as a "feed-in tariff") or can be offered to the free market through bilateral trade or organized markets (in more advanced systems). Likewise, the self-consumption limit can be a physical limit, stating that no more than defined percentages of kWhs (kilowatt hours) or kWs (kilowatts) can be injected to the grid; or a financial limit, stating that any excess energy above the limit will not be paid for, and will be available for the system to benefit from.

In many countries, high electricity consumption for industrial and commercial needs have been met through captive power installations rather than dependence on unreliable grid electricity. Historically, captive generation originates from large consumers' needs for reliable and sometimes cheap (based on tariffs and mostly when there is cross subsidization in the system) energy for their own consumption. For instance, industrial users such as steel mills, petroleum refineries, mining projects, and petrochemical plants in developing countries require uninterrupted power and pursue captive power projects due to their reliability and the operator's ability to control increases and decreases in generating capacity in alignment with their production cycles.[2]

As an illustration, mining industry projects in South America and Southeast Asia have installed captive power projects to provide unwavering, reliable electricity to power industrial operations that require uninterrupted electricity to maintain safe and consistent functionality. Captive power in the form of cogeneration[3] or trigeneration[4] can be appealing to operators when heating or cooling is needed by their main industrial or commercial process, or if it generates extra economic value through sale of heating or cooling services.

Conventional captive power equipment includes heat exchangers, boilers, transformers, generators, and turbines, among others – but numerous countries worldwide have prioritized renewable resources for captive power generation, a trend anticipated to lead captive power investments in the short-term and distant future. These mostly fall under DER, and they are physical and virtual assets deployed across the distribution grid typically close to load, and usually behind the meter; they can be used individually or in aggregate to provide value to the grid, customers, or both.[5] It is fair to say that with RE captive power implementations the objective is direct economic benefit rather than increased reliability compared to grid, and intermittent RE generators tend to use grid as back up for increased reliability. Even though DER became a more widespread example of captive generation, it still is important to note that captive power can range from hundreds of megawatts (MW) to a few kW, and can be connected to high and medium voltage as well as low voltage based on different applications and sizes. DER comprises only a *portion* of captive power and is a recent phenomenon due to the globally declining technology costs, such as with the case of solar panels decreasing in price significantly over the last decade.

In Rwanda, solar photovoltaic (PV) home systems are currently the main application of captive power. But for countries, including Rwanda, captive power also constitutes a promising opportunity for electrification. Industries using captive power can share their energy with the surrounding settlements as captive generators supplying energy to the grid or to mini-grids operated by others; they can also operate mini-grids if they invest in necessary network infrastructure and transform themselves from captive power generators to mini-grid system operators, such as in Uganda. It is important to entertain the possible role captive supply can play in electrification efforts in Rwanda. This perspective can justify introduction of flexibility in the self-consumption requirement to the regulatory framework or ease in transitioning to a regular license for captive generators. The world of captive power solutions entails a wide range of potential benefits for Rwanda's energy future. In order to provide a wide spectrum of information pertaining to captive power and DER in other countries, this report explores case studies examining the history of captive power (and DER where relevant) in the following countries.

3. Case Studies

The following case studies are provided to demonstrate the variety and flexibility of design for regulating captive power and DERs. Varying regulatory approaches are utilized depending on the intended use,

[2] Captive Power Generation – An Africa Guide. Norton Rose Fullbright. June 2016. https://www.insideafricalaw.com/publications/captive-power-generation
[3] Cogeneration or combined heat and power (CHP) is the use of a heat engine or power station to generate electricity and useful heat at the same time.
[4] Trigeneration or combined cooling, heat and power (CCHP) refers to the simultaneous generation of electricity and useful heating and cooling from the combustion of a fuel or a solar heat collector.
[5] "Distributed Energy Resources 101: Required Reading for a Modern Grid." Advanced Energy Economy. February 2017. https://blog.aee.net/distributed-energy-resources-101-required-reading-for-a-modern-grid

interconnection, and generation source(s) as well as technical and geographical challenges based on each country context. Widespread use of captive power, and DERs, can pose unique technical and regulatory challenges so countries the world over are utilizing many methods for regulating such power to ensure a stable, reliable and efficient grid. The following case studies may be found below, organized by country and address various approaches to captive power regulation:

- United States: A Case Study of Captive Power Metering
- Nigeria: A Case Study in Regulating Captive Power Created by Larger Generators
- Kenya: A Case Study of Regulating Solar PV Power
- Uganda: A Case Study in Isolated Grid Regulation
- Turkey: A Case Study on Combined Heat and Power

3.1. United States: A Case Study of Captive Power Metering

Technological advances have lowered costs for solar PV panels, naturally yielding increased interest and investment in residential rooftop solar installations. Policies and regulations, such as net metering programs and net billing mechanisms to regulate engagement between rooftop solar energy generators and their local utilities, have been instrumental in encouraging widespread rooftop solar in the U.S.

Initially, rooftop solar rose in popularity as it helped reduce customers' bills; however, when combined with other demand-side resources, it became evident that economic benefit was not the only reason various demand-side energy solutions attracted interest and investment in the U.S. Other factors including environmental considerations and reliability benefits also attracted investment in implementing DER. Environmental concerns include climate change, pollutant and greenhouse gas emissions, and energy-facility siting issues. Additionally, grid reliability concerns in certain countries have been cited to justify DERs. Large power plants can take many years to build, while service areas may have imminent electricity needs, which can often be met by DERs. However, the advent of rooftop solar, battery storage pilot projects, and energy efficiency programs required that regulators in the U.S. acknowledge the need to prepare coherent strategies to integrate these new technologies, as they share many technical and usage characteristics - and pose similar challenges to traditional grid operations.

California, which has emerged as a leader in DER roll-out, is an example of innovation in DER policies. Since 2007, the California Public Utilities Commission (CPUC) has sought to integrate demand side energy solutions and technologies by requiring that utilities provide an offering of curated programs. Decision (D.07-10-032) directs that utilities "integrate customer demand-side programs such as energy efficiency, self-generation, advanced metering, and demand response, in a coherent and efficient manner."[6] The gradual integration of demand-side programs and technologies is expected to achieve maximum savings while avoiding duplicative efforts, reduce transaction costs, and minimizing customer confusion. This effort led to the CPUC's endorsement of the 2016 *Distributed Energy Resources (DER) Action Plan* to align the organization's vision and actions in shaping California's DER future.[7] The plan outlines a projected DER policy vision over the next several years, and serves as a roadmap for coordinating activities across multiple proceedings as California continues its commitment to greenhouse gas emissions reductions and reforming utility distribution planning, investment, and operations. The plan serves as a guide for decision-makers, staff, and stakeholders as they facilitate forward-thinking DER policies.[8] California's proactive approach presents a useful example of an electricity regulatory body taking preliminary policy steps to smoothly accommodate and guide these growing technology towards symbiosis with the traditional grid system.

[6] https://docs.cpuc.ca.gov/published/Final_decision/74107.htm

[7] https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/DER%20Action%20Plan%20(5-3-17)%20CLEAN.pdf

[8] "Distributed Energy Resource (DER) Action Plan." California Public Utilities Commission. https://www.cpuc.ca.gov/General.aspx?id=6442458159

Net Energy Metering

Net energy metering (NEM), or simply net metering, became a popular program for electricity customers accompanying the growth of DERs in the U.S. NEM was created in the 1980s to assist a nascent renewable RE industry, and has now grown to exceed 8,000 MW of installed solar capacity among residential and business rooftops across the U.S.[9] At their inception, traditional net metering programs were embraced due to their simple, low-cost, and easily administered operating methods. State-level policies can permit a utility customer to generate electricity through distributed generation on-site to offset the customer's load and deliver any excess electricity to the utility for the applicable retail energy rate. DER customers are able to bank their excess kWh onto the electric grid during peak hours of energy production when their usage is limited - and receive credits that they can use later when their energy usage exceeds their production capacity.

Although state legislators, public utility commissions (PUCs), DER owners, and utility providers have been able to identify benefits of net metering policies, programs moving forward are evolving to meet unforeseen implementation challenges. States, PUCs, and individual private utility companies are creating new NEM programs intended to accommodate all stakeholders involved in the electricity sector.

Early Benefits & Traditional NEM Programs

For all parties involved, NEM programs delivered diverse benefits. Various states have goals including promoting renewable energy, easing pressure on the grid during peak hours, diversifying their energy resource portfolios, stimulating local economies, and simplifying procedures and reducing the costs affiliated with interconnecting small customer-owned generators.[10] NEM policies provide economic incentives to support RE technologies and encourage private sector investments in the RE industry, furthering technological advancement and economies of scale, ultimately assisting states in achieving related goals and objectives.

When customers generate electricity during high system demand periods, they flatten a utility's load profile. By adopting net metering policies, utilities can improve their distribution voltage performance, save fuel expenses, and avoid line losses. On average, for every kWh generated by a utility-scale generator, five to ten percent of the electricity will be lost en route to customers through transmission and distribution losses.[11] Such losses are mitigated when customers are able to generate electricity themselves, on-site, yielding clear benefits for both utilities and customers. Additionally, pivoting to on-site DER facilities illustrated twofold perks for customers. Financially, customers were able to ease their economic constraints through self-generation. Additionally, noneconomic factors such as environmental considerations and self-sufficiency also served (and still serve) as key drivers accelerating interest in on-site DER such as rooftop solar.[12]

Although there were initial benefits of implementing NEM programs, it became apparent that a majority of utilities opposed net metering programs for several reasons. A primary concern was the additional state and federal mandates imposed on them through PURPA and FERC requirements, which affected the utilities' bottom lines. More specifically, the rule requiring utilities to purchase power from qualifying co-

[9] Paul Zummo (American Public Power Association); Rate Design for Distributed Generation: Net Metering Alternatives with Public Power Case Studies; June 2015

[10] Ibid.

[11] Jason B. Keyes & Joseph F. Wiedman (Interstate Renewable Energy Council); A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering; January 2012

[12] Ibid.

generation and small power production facilities at the utilities avoided cost would be costly and raise rates, potentially leading to customer complaints.[13]

Throughout the 1990s, NEM programs saw a slow implementation rate. Utilities did not communicate or advertise available NEM programs to their customers, and low electricity prices and high costs affiliated with renewable energy systems led to limited participation of residential customers in on-site generation. Additionally, interconnection requirements imposed by utility providers and a dearth of regulatory orders for NEM guidelines further impeded implementation.[14]

When the first NEM policies were created, they were intended to not only encourage the adoption of renewable energy technologies, but also to address the small minority of DER customers and provide a de facto pricing mechanism out of convenience.[15] In a small regulated market with only one utility interacting with a small amount of customers, traditional net metering is a simple and straightforward process. Alternatively, in a competitive, retail choice market, the process can become more complex as more parties participate, including both consumers and providers.[16] The concerns utility providers and state regulators had about the pricing discrepancy were justified, and would eventually have to be addressed as NEM programs continued to grow.

Current Challenges: NEM Programs

As more U.S. states began to adopt NEM programs in the early 2000s, the growth of DER expanded rapidly, mainly due to encouraging federal and state tax incentives. These incentives were the driving force behind solar PV installations and today can cover up to 70 percent of the total cost of solar PV panels in some states.[17] While the consumer-owned DER facilities began to grow, the complexity and challenges of serving this specific customer base at the established retail rate became more apparent. Typical residential utility bills have many components, including a fixed monthly customer charge and a variable energy charge. Utilities recover most of their fixed costs through the variable rates on customer billing.[18] Paying the customer for solar generation at the retail energy charge thus implies that energy charges are only collecting the utility's variable generation costs, while utilities actually need to recover a combination of generation, transmission, and distribution capacity costs through their energy charges as well since the fixed charges are not enough to compensate for these costs.[19]

As a result, due to the traditional retail rates, net metering results in a revenue shortfall for the utility. This net loss is made up through higher energy charges for not just DER-consumers, but from consumers who are not a part of net metering programs.[20] As a result, non-DER consumers, who receive no direct monetary benefits of a NEM policy, cross-subsidize DER-owners[21] to ensure that the utility is able to fully recover all of their costs.

As NEM becomes more widespread, rate analysts and researchers are developing new rate models to help ensure that utilities recover their costs of service while also providing appropriate incentives for

[13] Ibid.
[14] Ibid.
[15] Paul Zummo (American Public Power Association); Rate Design for Distributed Generation: Net Metering Alternatives with Public Power Case Studies; June 2015
[16] Justin Barnes & Laurel Varnado (Interstate Renewable Energy Council); The Intersection of Net Metering & Retail Choice: An Overview of Policy, Practice, and Issues; December 2010
[17] Paul Zummo (American Public Power Association); Rate Design for Distributed Generation: Net Metering Alternatives with Public Power Case Studies; June 2015
[18] Ibid.
[19] Ibid.
[20] Ibid.
[21] Tom Stanton (National Regulatory Research Institute); Review of State Net Energy Meting and Successor Rate Designs; March 2019

renewable energy consumers. By 2015, 43 states and the District of Columbia had NEM programs for at least some of their regulated utility companies.[22] Traditional net metering has been the most widespread solar policy among states in the U.S., so the urgency to address the revenue shortfalls in the rate design have been imperative for all stakeholders involved.

In the U.S., a consensus has formed that initial NEM policies—originally intended to support nascent markets for marginally cost-reflective solar PV—have served their purposes, and the time has come to replace them with cost-based or value-based tariffs.[23] As of 2017, states including Arizona, Maine, Hawaii, and Indiana have rolled back or reduced their traditional net metering programs.[24] Currently, state regulators and utilities are considering modified approaches to net metering and have engaged in studies of the long-term benefits and costs of distributed generation.[25] Policymakers stress the importance of analyzing and assessing the costs associated with DER in their jurisdictions so that they can establish cost-reflective rates.[26] Policy reforms that are hastily rushed and poorly planned can yield unintended consequences, including volatile business conditions such as boom and bust cycles for DER industries.[27]

NEM Alternatives

Value of Solar (VOS)

A new alternative to implementing net metering mechanisms is the development of value of solar rates into tariff models. Austin Energy, a Texas utility, created its own VOS tariff based on an algorithm that incorporates six value components: loss savings, energy savings, generation capacity savings, fuel price hedge value, transmission and distribution capacity savings, and environmental benefits.[28] VOS is an effort to associate a quantifiable benefit with each kWh of distributed solar exported to the grid. Austin Energy's VOS rate represents a break-even value for a specific kind of distributed generation resource and a value at which the utility is economically neutral, whether it supplies such a unit of energy or obtains it from the customer.[29]

A benefit to the VOS rate model in comparison to the traditional retail rate is that VOS can be calculated and used as a point of reference to see how current estimates relate to wholesale avoided costs or retail prices. VOS rates can also be used to understand what current and near-term future DER cost compared to the calculated values, with and without various financial incentives.[30] As for the consumers who are affected by this new model, the process of traditional net metering would be the same, with the difference of substituting the VOS rate instead of the retail rate.

It should be noted that different VOS rates could apply to different regions and jurisdictions depending on a variety of components, including different market structures, energy prices, and congestion points in regional transmission organizations (RTOs). For example, Lincoln Electric System (LES), a utility operating in Nebraska, discovered that their VOS rate is roughly half the cost as compared to its retail rate. For Austin Energy, their VOS rate was much closer to the retail rate.[31]

[22] Ibid.
[23] Ibid.
[24] "Rooftop solar has a good decade but a bad year." Marketplace. https://www.marketplace.org/2017/07/17/sustainability/rooftop-solar-has-good-decade-bad-year/
[25] Tom Stanton (National Regulatory Research Institute); Review of State Net Energy Meting and Successor Rate Designs; March 2019
[26] Paul Zummo (American Public Power Association); Rate Design for Distributed Generation: Net Metering Alternatives with Public Power Case Studies; June 2015
[27] Tom Stanton (National Regulatory Research Institute); Review of State Net Energy Meting and Successor Rate Designs; March 2019
[28] Paul Zummo (American Public Power Association); Rate Design for Distributed Generation: Net Metering Alternatives with Public Power Case Studies; June 2015
[29] Ibid.
[30] Tom Stanton (National Regulatory Research Institute); Review of State Net Energy Meting and Successor Rate Designs; March 2019
[31] Paul Zummo (American Public Power Association); Rate Design for Distributed Generation: Net Metering Alternatives with Public Power Case Studies; June 2015

Residential Demand Charge

A central Florida utility provider, Lakeland Electric, had been operating under a traditional net metering tariff for a number of years but wanted to efficiently adjust their rate model to reflect a more true cost associated with their DER-customers. After conducting a cost of service analysis, the utility decided that DER-customers on PV systems would be on a demand pricing rate schedule.[32] Residential customers would pay a $4.80 per kW-month demand rate. Solar output would still be credited at the energy rate, but the energy rate would then be lower. The demand rate is intended to be a fair representation of the capacity that the utility is required to stand ready to supply the DER-customer.[33] More importantly, the purpose of this modified rate is to better align revenue to costs. While making this adjustment, Lakeland Electric made sure to continue their mission of customer engagement and held a series of workshops with legislators, various stakeholders, and public hearings before implementing their demand charges. To date, eleven states have added system-capacity based demand charges for customers with distributed generation.[34]

Buy-all, Sell-all Rates

A simple alternative to net metering is buy-all, sell-all rates in which customers purchase all energy consumed at the utility's retail rate, and then separately sell all their surplus rooftop generation to the utility as avoided costs. This model is similar to the VOS approach, as consumption and generation are treated as separate services with different price points and rate designs.[35] Buy-all, sell-all rates treat all on-site production the same, regardless whether the energy is consumed on-site or exported to the grid.[36] This simple approach is gaining in popularity and several U.S. states such as Connecticut, Maine, Colorado and Georgia have moved to or adopted a buy-all, sell-all billing option.[37]

Virtual Net Metering (VNEM) and Community Solar Programs

Similar to traditional net metering, virtual net metering essentially allows a wider share of participants to participate in a community solar program that might not be an on-site DER producer themselves, thus creating an effective model of economies of scale and bill savings. Virtual net metering expands consumer options for RE by removing significant hurdles commonly associated with tradition NEM programs[38] such as having the ideal location or resources to install their own systems. By allowing multiple residents in an area install a single solar electric system for the benefit of the building or land, a more cost-effective design is enabled as compared to the traditional NEM system arrangement for one RE system physically installed and connected to one utility account. During these programs, bill credits accrue monthly for each participating customer according to each customer's share of the total output of a community solar project.[39] Many U.S. states are working on including low- and middle-income customers into VNEM programs to serve a wider range residents in specific communities.

Conclusion

In order to ensure that utility providers recover their costs as new NEM programs begin to emerge, it is imperative to continue customer engagement and address their needs simultaneously. Consumers of DER facilities are essential components of the rate-setting process. The U.S. is now beyond the initial stages of

[32] Ibid.
[33] Ibid.
[34] Tom Stanton (National Regulatory Research Institute); Review of State Net Energy Meting and Successor Rate Designs; March 2019
[35] Paul Zummo (American Public Power Association); Rate Design for Distributed Generation: Net Metering Alternatives with Public Power Case Studies; June 2015
[36] Tom Stanton (National Regulatory Research Institute); Review of State Net Energy Meting and Successor Rate Designs; March 2019
[37] Ibid.
[38] Center for Sustainable Energy (California Solar Energy Industries Association, Interstate Renewable Energy Council); Virtual Net Metering Policy Background and Tariff Summary Report: Solar Market Pathways; June 2015
[39] Tom Stanton (National Regulatory Research Institute); Review of State Net Energy Meting and Successor Rate Designs; March 2019

distributed generation as more customers continue to install on-site DER facilities, resulting in practical and affordable solutions to meet diverse power generation needs among customers.

One of the most popular components of traditional NEM programs in the U.S. is their simplicity for consumers. As utility providers and state PUCs begin to experiment and roll out new NEM programs, they should be aware that complex rate structures can overwhelm and confuse customers, so continuing customer communication and holding public engagements within their jurisdictions to explain the programs and changes is a vital step in ensuring transparency and understanding.[40]

The history of traditional net metering has illustrated a successful balance of roles among the three primary authorities and entities involved —state lawmakers, PUCs, and utility companies. Various individual utility providers are fully aware that customer-owned DER is here to stay and will continue to grow, and U.S. utilities are currently taking the necessary measures to safeguard DER programs and ensure their success. Of course, there will still be challenges in the future for all parties involved. In the process of finding the right successor tariff, stakeholders face the challenge of balancing uncertain costs and benefits with the right mix of detail and flexibility in a new rate structure for net metering.[41]

3.2. Nigeria: A Case Study of Captive Power Created by Larger Generators

Among countries in Africa, Nigeria is regarded as a leader in pioneering captive power initiatives and regulation. Many households and companies in Nigeria now utilize captive power generation solutions to deliver consistent electricity supply for household needs and industrial operations. Given Nigeria's recent population expansion and industrial growth, the country's electricity demand has significantly increased beyond the grid's generation capability and access. Poorly maintained generation and grid infrastructure has also contributed to unstable electricity supply, impelling many to pursue captive power generation alternatives for more consistent and reliable power. Subsequently, as of 2015, 96% of electricity consumed by Nigerian industries was produced through captive power from oil and gas or biomass products – and a total of 1,300 MW in captive power permits had been issued.[42] This figure illustrates the strong preference for captive power solutions exhibited by the vast majority of industrial production needs in Nigeria, reflecting a general consensus that captive power is more reliable than conventional grid electricity.

Given these circumstances, Nigeria has maintained an official national captive power regulation since 2008. The Nigerian Electricity Regulatory Commission (NERC) oversees Regulation No: NERC-R-0108: *Regulations for the Granting of Permits for Captive Power*.[43] This regulation explicitly defines captive power generation as "the generation of electricity exceeding 1 (MW) for the purpose of consumption by the generator, which is entirely consumed by the generator itself, and not sold to a third-party."[44] The regulation thus only applies to captive power that is generated for self-consumption, and excludes those operating captive power facilities who are interested in supplying surplus power exceeding 1 MW to an off-taker selling surplus power. The objective of the regulation is to ensure the optimal utilization of resources for the provision of electricity services through establishing registries of information related to

[40] Paul Zummo (American Public Power Association); Rate Design for Distributed Generation: Net Metering Alternatives with Public Power Case Studies; June 2015

[41] Tom Stanton (National Regulatory Research Institute); Review of State Net Energy Meting and Successor Rate Designs; March 2019

[42] "Captive Power in Nigeria: A Comprehensive Guide to Project Development.' Africa-EU Renewable Energy Cooperation Programme & Africa-EU Energy Partnership. https://www.ctc-n.org/sites/www.ctc-n.org/files/resources/published_market_study_captive_power_nigeria_am1.pdf

[43] Paul Zummo (American Public Power Association); Rate Design for Distributed Generation: Net Metering Alternatives with Public Power Case Studies; June 2015

[44] Nigerian Electricity Regulatory Commission. Regulation No: NERC-R-0108: *Regulations for the Granting of Permits for Captive Power. 2008.* *https://nerc.gov.ng/nercdocs/Regulation-for-Captive-Power-Generation.pdf*

captive supply and to ensure the safety of service in the production and delivery of electricity for self-consumption and to an off-taker not exceeding 1MW (after receiving written consent of the NERC).

The captive power regulation provides definitions of relevant terms, detailed requirements for permit applications submitted to NERC and subsequent evaluation processes, parameters allowed for surplus power generators, power thresholds, amendment and renewal processes for permits, and other key provisions[45] required to fully inform those interested in applying for permits to operate captive power projects. The regulation itself includes schedules providing documentation for permit applications, applications for permit amendments and renewals, and fee schedules providing specific required fees accompanying permit application, amendment, and renewal applications submitted to NERC. Key provisions include the following:

Form of Application
Section 3 of the regulation specifies submission requirements for applicants "wishing to construct, own, maintain, install, and/or operate a captive generating plant."[46] An official application for a permit to operate a captive power system is included in Schedule 1 of the regulation, as well as the NERC website. The rules instruct applicants to provide electronic and hard-copy applications to the Commission Secretary with a non-refundable fee.

Evaluation of the Application
The regulation states that the Commission may request additional information from the applicant to complete their evaluation of the respective permit application, which must be provided within one month of the notification date. Beginning on the date of formal application receipt at the Commission, there is an established time window of 30 days within which the Commission is required to acknowledge official receipt of *completed* permit applications. These provisions ensure applicants that the Commission is accountable and is guaranteed to evaluate and issue decisions on applications in a timely manner, elaborated upon below.

Approval or Refusal of Permit
The Commission reserves the right to issue or refuse permits to applicants; following official Commission acknowledgment of complete application receipt, there is a three-month window within which the Commission is required to review and issue decisions on permit applications. Upon approval, the Commission informs the applicant of the approval and required conditions, including fees required before the permit is officially granted. Should the Commission refuse to issue a permit, it must notify the applicant in writing and provide reasons for the refusal. Should an applicant wish to appeal the rejection, he/she must do so within 21 days of the refusal issuance. Any Commission-issued permits are approved with terms and conditions as fixed by the Commission.

Surplus Power
Should a permitted captive power system operator wish to supply surplus power from that system to an off-taker under 1 MW, that permit holder must apply for written consent from the Commission prior to engaging in the power purchase agreement (PPA). A permit holder interested in supplying surplus power exceeding 1 MW to an offtaker must apply for a proper generation license in compliance with Nigeria's Electric Power Sector Reform Act 2005. As such, NERC does not allow captive power system operators to sell surplus power to offtakers beyond 1 MW without obtaining a proper generation license.

Data & Information Submission Requirements

[45] Ibid.
[46] Ibid.

Chapter IV of the regulation divulges on detailed data requirements governing information submitted by permit holders operating captive power plants. Requested from time to time from the Commission, documentation from system operators must provide information on health, safety standards and procedures, environmental issues resulting from operation, and any other relevant data requested. Notably, the Commission reserves the right to enter and inspect the premises of a captive power facility at any time to ensure compliance with regulations, terms and conditions. Additionally, a permit holder must receive Commission approval for any major modifications to a captive power plant – which shall be issued within five working days of the submitted request. All modifications to a captive power plant's capacity must be reported to the Commission within 24 hours of the augmentation.

Enforcement and Penalties

The Commission can penalize permit holders (or cancel their permits) for violating any terms and conditions. Any permit holder must implement or follow Commission orders and written notices; if a permit holder does not intend to comply with the latter, the Commission reserves the authority to order cessation of operations and issue other orders as necessary to prevent the continuance of the "contravention." Permit holders are entitled to take legal action challenging the Commission's order or notice, should they choose to protest such a ruling.

> *Penalties for Violation of Regulation:* Any person who violates the regulation is liable on conviction; first offenders are subject to a fine not exceeding N100,000.00 and/or to imprisonment for a period not exceeding one year. Subsequent convictions are subject to a fine not exceeding N500,00.00 and/or imprisonment for a period not exceeding three years. These penalties, which include prison sentences, are serious and an imprisonment clause not recommended for inclusion in a regulation, as it can deter potential project developers and stifle technological adoption.

> *Penalties for Failure to Comply with Commission Requests or Inspections:* Any person who fails to furnish a return or supply requested information in the prescribed time period, or provides a false or incomplete return or information, effectively commits an offense and is liable to a fine not exceeding N100,000.00 and/or to imprisonment for a period not exceeding one year.

Permit Amendment, Renewal, and Cancellation

Terms and conditions of a permit may be amended through application by the permit holder, by the Commission's own initiative, or upon reception of a complaint from any consumer, eligible customer, consumer association, licensee, or other permit holder. Any application for amendment to a permit requires an application submission fee and must be granted by the Commission. Applications to renew permits must be submitted, with the accompanying fee, at least three months prior to the permit's expiration date. The Commission notes that its review process for renewal applications will closely resemble that of the permit application process.

The Commission may *cancel* a permit if:

1) It was issued through fraud or misrepresentation/nondisclosure of known information
2) The permit holder willfully contravened any provisions within the regulation
3) The permit holder fails to comply with any term or condition in the permit
4) The permit holder becomes insolvent or declares bankruptcy

Should a cancellation occur, the Commission shall notify the permit holder of its intended cancellation and provide justification. The permit holder has the opportunity to demonstrate that the problematic criteria have changed, such that there are no longer grounds for official cancellation. Should the Commission proceed with cancellation, it notifies the permit holder with an effective cancellation date on which all operations at the captive generation plant must cease. In some cases, rather than cancelling the permit altogether, the Commission may pass another order imposing further terms and conditions that the permit holder must comply to in order to continue operation.

Embedded Generation Provisions in Nigeria
Another classification in Nigeria that resembles the captive power concept in Rwanda from the perspective of connection point is embedded generation. Embedded generation regulation provides examples on how the connection to the system is handled and also how the energy injected to the system is priced.

Regulation 35 Nigerian Electricity Regulatory Commission (Embedded Generation) Regulation 2012 (NERCER) made pursuant to the Electric Power Sector Reform Act (EPSRA) defines embedded generation as "the generation of electricity that is directly connected to and evacuated through a distribution system." [47] It is electricity generated by an independent generator and evacuated via the grid. Although self-consumption is not a requirement for embedded generation in Nigeria, the terms in the Regulation related to the connection to grid and the sale of energy may be useful for Rwanda.

According to NERCER:

- The Distribution Licensee shall negotiate in good faith and offer fair and reasonable terms for the connection of an embedded generation unit in accordance with the provisions of these Regulations and any other relevant regulatory instruments that may be issued by the Commission. The distribution licensee (DL) is expected to make access to the distribution system available to the embedded generation licensee *where there is capacity* after reaching an agreement with the embedded generation licensee on acceptable conditions, including fees.
- The maximum embedded generation capacity allowed for a given distribution system shall be a percentage of the peak system load of the Distribution Licensee's distribution system, which shall be determined by the Commission from time to time.
- The Embedded Generating Units exceeding 5MW shall comply with applicable provisions of the Grid Code. Generating units with capacity of 20MW and above shall be centrally dispatched by the System Operation Licensee in accordance with the provision of the National Electric Power Policy.
- Pursuant to the provisions of the Act and subject to the declaration of Eligible Customers by the Minister, the Embedded Generation Licensee may enter into agreements with Eligible Customers and the end-user customer tariff shall be negotiated between the parties.
- Feed-In-Tariffs ('FITs') approved by the Commission, shall be applied for energy produced by Renewable Energy Embedded Generators and shall be fixed for a specified period, subject to periodic reviews and approval by the Commission.
- An embedded generator is generally prohibited from engaging in the business of distribution, transmission, trading, and systems operation as these are differently regulated under the *EPSRA*. However, where NERC is satisfied that there would be no abuse of market power, a holding or subsidiary company of the EG may be licensed to engage in these regulated activities.
- Distribution losses are assigned to embedded generation using distribution load factors which are determined by the System Operator using methodology that is agreeable to all participants.

Conclusion
The captive power regulation in Nigeria specifically handles larger generators (above 1 MW) and although the definition of captive power requires the energy generated to be entirely consumed by the generator itself, and not sold to a third-party, the articles allow supply of surplus power to an off-taker under 1 MW once a permit is received from the Commission prior to engaging in the PPA. These seemingly inconsistent

[47] *https://nerc.gov.ng/index.php/component/remository/Regulations/NERC-(Embedded-Generation)-Regulations-2012/?Itemid=591*

articles show the need for a flexibility in designing the captive regulation, as the captive generation can play a significant role in providing generation adequacy for the electricity system once and if the system needs them, if the generation is interconnected with the main grid.

Alternatively, the Embedded Generation Regulation of Nigeria provides examples on how surplus energy can be marketed, the losses handled, connection capacity might be determined, and what the role of the utility can be in defining the connection terms to the grid. It is also observed that within the scope of embedded generation, Nigeria differentiates the mechanism and the price of sale of the surplus energy for renewables.

3.3. Kenya: A Case Study of Regulating Solar PV Power

Another country in Africa with high incidence of captive power generation systems is Kenya. Flower and vegetable farming industries led the way in terms of captive power uptake to power required industrial practices, and many Kenyan commercial and industrial businesses have installed captive energy systems (many of which are powered by renewable energy sources) to help power their operations on premises. It is also notable to point out that Kenya has one of Africa's highest installed capacity or decentralized off-grid solar PV systems, illustrating the viability of off-grid renewable generation in the country at present.

With roughly 3,900 commercial and industrial power consumers in Kenya as of 2018, there is immense potential for solar PV captive power systems for self-consumption among these entities, many of which use diesel generators to provide 15% of their consumed electricity and can shift to cleaner, cheaper solar captive generation. Currently, wind, solar, and biomass generation is used for captive power plants by the flower, fruit & vegetable and tea industries, as well as schools and universities. Solar PV-powered captive generation has grown significantly in recent years to a total of 40 MW nationwide, and is used for industrial and commercial purposes, but notably serves a wider market including office buildings, tourism, telecommunications, and hospitals.[48] Kenya's captive power generation is "greener" than that of Nigeria and many other countries in Africa; while Nigeria's captive power systems are largely diesel or biomass-based, Kenya has a plethora of solar PV captive power generation systems.

Kenya currently exhibits three main types of captive solar PV options:

1) PV grid-tied solar systems: for grid-connected consumers with high consumption during the day, this system supplements daytime consumption. This is used by manufacturing and commercial facilities.
2) PV diesel hybrid systems: for grid-connected or off-grid consumers running diesel generators as their main power sources, they can install a PV system to supplement their diesel generators.
3) PV battery storage hybrid: For off-grid consumers, a PV battery storage hybrid presents an appealing option with flexibility for dark hours.

Under Kenya's Energy Act, any person who wishes to generate, import or export, transmit or distribute electrical energy is required to obtain a license or permit from the Kenya Energy Regulatory Commission (succeeded by the Energy & Petroleum Regulatory Agency of Kenya (EPRA)). However, per EPRA's *Licensing of Commercial and Industrial Solar Photovoltaic Projects* document, electricity end users with captive (own) generation of cumulative capacity not exceeding 1 MW do not require authorization from EPRA.[49]

They are advised to engage contractors and workers duly authorized by EPRA for purposes of installation, and comply with other statutory requirements such as the Electricity Act.[50] Additionally, the EPRA's

[48] "Kenya: Renewable Energy Potential." Get.Invest. https://www.get-invest.eu/market-information/kenya/renewable-energy-potential/
[49] Kenya Energy & Petroleum Regulatory Authority. *Licensing of Commercial and Industrial Solar Photovoltaic Projects*.
[50] Government of Kenya. *The Energy (Electricity Licensing) Regulations, 2012*.

Internal Procedures and Guidelines for Regulating Mini-Grids[51] governs mini-grid applications and system requirements, and defines a mini-grid in Kenya as "any electricity supply system with its own power generation capacity, supplying electricity to more than one customer and which can operate in isolation from or be connected to a distribution licensee's network."

Thus, this framework applies to captive power systems under 3 MW intended to provide electricity supply to other consumers. The framework specifies, in detail, the procedures and guidelines required for adherence by mini-grid developers, including site identification, applications for generation permits, distribution and supply permits, construction permits, and extensive tariff documentation for approval from EPRA. The document includes detailed annexes providing technical and documentation requirements and application forms, making it straight-forward and clear for interested parties to apply with EPRA.

Conclusion

Though Kenya does not maintain an explicit captive power regulatory framework, EPRA regulates captive power systems through a confluence of related documents governing relatively small off-grid and grid-connected generation systems. This has proved to be a successful approach thus far, as illustrated by the high prevalence of captive power generation systems in Kenya, many of which are powered by renewable energy infrastructure.

Kenya represents a relatively mature market for PV diffusion relative to other Sub-Saharan African countries, with market actors that specialize in designing PV system equipment, installation and maintenance services, and financing options.[52] Facilitating similar circumstances may be of interest to regulators in Rwanda interested in furthering the prevalence, accessibility, and viability of solar PV captive power systems. However, time will tell whether EPRA should pursue an explicit captive power regulation governing these systems specifically, rather than through cross-referencing multiple related regulatory frameworks.

3.4. Uganda: A Case Study in Isolated Grid Regulation

Uganda currently has a 28% national electrification rate and an 18% rural electrification rate, representing one of the lowest electrification incidences in Africa.[53] Independent power producers (IPPs) currently account for nearly 60% of 916 MW of installed generation capacity. Given Uganda's spatially disparate population distribution and low rural electrification rate, DERs provide an appealing solution to help achieve rural electrification goals; as such, DER utilization is gaining interest and momentum in Uganda.

Currently, Uganda does not maintain specific policies or a regulatory framework governing captive power use, nor does Uganda maintain an explicit DER policy. However, the Uganda Energy Regulatory Authority (ERA) provides support for distributed generation, renewable energy, and private sector investment through Uganda's Electricity Act of 1999 and has drafted its national isolated-grid (mini-grid) systems regulation to include provisions addressing captive power generation. Given the growing international appetite for investment in Uganda's isolated-grid sector, regulators in Uganda expect that an impending influx of investment in the sector will help to advance electrification goals and achieve rural electrification targets through renewable and small scale electrification infrastructure.

Uganda's absence of a regulatory framework governing isolated grid systems and captive power has long discouraged investment in the country's off-grid sector; this lack of clear rules and regulatory certainty has created increased perceived financial risk for potential investors. Nonetheless, a large number of

[51] Kenya ERC (formerly the Energy Regulatory Commission, now EPRA). ERC's *Internal Procedures and Guidelines for Regulating Mini-Grids,* Version 1. February 2018.

[52] "Kenya: Renewable Energy Potential." Get.Invest. https://www.get-invest.eu/market-information/kenya/renewable-energy-potential/

[53] "Uganda Power Africa Fact Sheet." USAID. https://www.usaid.gov/powerafrica/uganda

developers and investors are interested in infrastructure projects that can rapidly increase rural electrification rates in Uganda through smaller-scale off-grid technologies and DERs. For this reason, international investors requested that ERA craft a regulation designed to provide regulatory certainty and incentivize isolated grid development by establishing a simple streamlined approach to achieve the legal ability to operate new systems.

Uganda's impending Isolated-Grid Systems regulation establishes parameters for registration and license exemption in line with Uganda's 1999 Electricity Act, which establishes foundational parameters governing the electricity sector. The proposed rules allow developers to register their small generation systems or obtain certificates of exemption instead of having to obtain licenses for isolated-grid infrastructure. These methods are designed to facilitate small generation systems and isolated grids as obtaining a license can prove a lengthy process that could discourage entities from investing and establishing infrastructure in Uganda.

Without a regulatory framework governing captive power, Uganda's current approach to captive power is to simultaneously encapsulate mini-grids and captive power systems through Uganda's 'Isolated-Grid System Regulation' recently drafted by ERA with support from USAID and NARUC. As of November 2020, this regulation has been approved by the Solicitor General's office for passage into national law. The regulation awaits publication in the National Gazette, upon which it will be *officially* recognized as a national law.

The impending regulation includes mandatory conditions for generators for commercial purposes. In this case, "commercial purposes" pertains to electricity that is generated with the primary purposes of either a) supporting commercial or industrial activities through captive power; or b) selling power to the primary grid.[54] Thus, developers and industrial/commercial consumers who are considering captive power options may fall under the proposed regulation. However, it is pertinent to highlight that depending on the actual purpose of the developer or consumer and the size of the installation, the isolated grid regulation may or may not apply to their cases.

The definition for isolated-grid systems and the use of captive power as specified in the isolated grid regulation can shed light on instances in which the two technologies could be interchangeable, and when their purposes are distinct. The respective definitions and usage provided are:

- "Isolated Grid System" refers to any isolated electricity supply system with its own power generation and distribution network, supplying electrical energy to consumers that is not connected to the primary grid.[55]
- "Commercial Purposes" means electricity that is generated with the primary purposes to either a) support commercial or industrial activities through **captive power**; b) is to be sold to the primary grid.
- A developer or operator of a generating station up to 500 kW for commercial purposes shall submit to ERA a Registration Form provided in Schedule 1 of the Regulation.

It is clear that these definitions may overlap; the actual purposes of a given generator and its connection to the grid are the decisive factors determining which regulation will apply to respective systems. In addition, the size of the installation is also essential in determining the process of registration, license or certificate of exemption that the operator will have to obtain.

Comparisons between Captive Power and Isolated-Grid Systems Regulation

[54] *Uganda's Draft Isolated-Grid System Regulation*. NARUC and the Electricity Regulatory Authority of Uganda. November 2019.
[55] Ibid.

Captive Power

It is important to highlight that the above definition for commercial purposes suggests that instead of applying for a license, commercial and industrial consumers can opt for registering their generators up to 500 kW. Importantly, however, residential consumers are not excluded from the captive power market and if they want to sell excess energy to the grid they also have to register their generation. There is increasing interest in the captive power market due to considerations such as cost savings, improved reliability of power supply and reduced exposure to electricity tariff fluctuations.[56] Naturally, the size of the respective consumer and the site determine the project's feasibility, which must ultimately be registered with, and sometimes approved by, the regulator.

Uganda's captive power plants generate electricity through solar or biomass sources, each respectively presenting a different set of challenges. To diversify generation sources and propel the country towards renewable energy systems, ERA has engaged efforts to foster a welcoming investment climate and a promising market for solar PV and bioenergy captive power at the commercial and industrial scale.[57] Currently, the captive power market is at a "proof of concept" stage of development awaiting to showcase what deems a project technically and financially feasible.

Since there is no clear regulation regarding the sale of surplus electricity to the grid, most grid-connected customers are recommended to develop captive power projects that would not entail excess spillover to the grid. In principle, it is anticipated that on a case by case basis, some of the regulations that apply to distributed or embedded renewable energy generation IPPs could be applicable to captive power.[58] The country's power grid also has reliability issues that could place constraints on grid export from distributed generation sources. In addition, as of the end of 2018, Uganda did not have any net metering framework to compensate consumers for their sales of surplus electricity to the grid. One of the ways that captive power plants could sell surplus to the grid is under the Renewable Energy Feed-in Tariff (REFIT). However, this would require approval of a PPA and a complex licensing process which only project owners with export capacity over 500kW consider pursuing.

With no explicit regulatory framework for captive power, a self-generator must adhere to the 1999 Electricity Act, supplemented by the Isolated-Grid Regulations and other standards where applicable. For licensing or registration, a distinction is made for different sizes and types of captive plants as follows:

- For captive power generation for commercial purposes — **if the project is less than 500 kW,** there is no requirement for a license. However, the project should still register with ERA. This entails filing with ERA information regarding the technology, size, location, expected generation capacity and project timeframe. ERA will normally respond with a letter stipulating any conditions for the approval/exemption.

- "If the project is **larger than 500 kW,** even if there is no spill over to the grid (which is not allowed at the time of writing), or even if the facility is off-grid (except in the case described next), a generation license will be issued for own consumption, without any tariff review. In this case, the generation license application process, fees and reporting requirements will be applicable."[59]
    - Interpretation: For projects over 500 kW, the developers will have to go through a more lengthy process to obtain a license for generation approved by ERA. In case that the installation is not connected to the main grid and plans for local distribution of electricity then

[56] Matthew Woods, Timothy Cowman, Kevin Kerigu (Carbon Africa Ltd), Uganda: Captive Power Developer Guide, Brussels June 2019
[57] Ibid.
[58] Ibid.
[59] Matthew Woods, Timothy Cowman, Kevin Kerigu (Carbon Africa Ltd), Uganda: Captive Power Developer Guide, Brussels June 2019

the conditions below apply. In this case, the regulation defines a crucial distinction between projects connected to the grid and the isolated-grid systems.

- "However, if the **captive project is less than 2 MW** and plans for local distribution of electricity, it may be possible to obtain a **license exemption** under the draft Isolated Grid Regulation, which would save the applicant from paying higher licensing fees. This is at ERA's discretion."[60]
    - Interpretation: This regulation refers to the draft Isolated-Grid Systems Regulation. The draft regulation stipulates that "A person who intends to develop or operate an isolated grid system with a generation capacity not exceeding 2 MW shall apply to the Authority for a certificate of exemption [...]." In addition, "A person or developer shall be allowed to submit a single application for multiple isolated grid systems within the same geographical location provided that the total generation capacity of all isolated grid systems within each application do not exceed 2 MW." The certificate of exemption is the way that the regulator incentivizes this type of developments, as developers can avoid the lengthy licensing process and can start developing their projects in a more efficient manner. Moreover, it reduces the business risk burden for investors. Lastly the isolated grid regulation makes the process even easier by allowing the developer to submit a single application for multiple isolated grid system as long as their aggregate capacity does not exceed 2 MW. Once the isolated-grid regulation is approved and codified into law, captive power projects with plans for local distribution of electricity will have to adhere to this regulation.

- "If a captive plant (bioenergy only) wishes to sell excess energy to the national grid (regardless of its size), there would be a full licensing process under the REFIT and a PPA with UETCL (the distribution company) would be required, along with the licensing fee and quarterly reporting."[61]
    - Interpretation: Large industrial consumers are the players most likely to take advantage of this regulation. They will have to produce a significant excess of electricity to justify going through the PPA and licensing process.

- "Selling surplus captive power to third party grid or directly to consumers would require not only a generation license but also sales license, possibly a distribution license and a tariff review. Direct sale to third-party single buyers is currently not allowed."[62]
    - Interpretation: The regulation discourages the project owners to sell the surplus captive power to the grid or directly to consumers.

Comparison: Captive Power & Isolated-Grid Systems

The primary distinctions between captive power and isolated grid system regulations in Uganda are highlighted in the interpretations of the captive power regulation. The main point of emphasis is that that captive power systems with capacities under 500kw can be registered instead of acquiring a license. Captive power with capacities under 2 MW and plans for local distribution of electricity can adhere to the isolated grid infrastructure. In any other case, captive power would adhere to different regulation.

Additionally, the tariff structure is a continuous debate for both captive and isolated grid systems. However, pilot programs will be developed in order to better understand how to compensate electricity sold by these systems in the Ugandan context. Uganda's case proves that captive power can be incentivized

[60] Ibid
[61] Ibid
[62] Ibid

through robust regulation which provides investors and developers assurance that their investments are safe.

3.5. Turkey: A Case Study on Combined Heat and Power

Captive power in Turkey has been regulated under three different regimes in three different time frames of electricity market development. The first regulatory regime was for autoproducers and autoproducer groups. “Autoproducers” in Turkey refers to entities who produce electricity primarily for their own consumption. This regulatory regime was developed in the 1990s in order to:

- introduce private participation in the generation of electricity;
- when feasible, introduce cogeneration to boost efficiency; and
- remedy shortfalls in the adequacy of supply and related reliability problems.

The second wave of regulation came in 2013 for renewable generation to benefit license exemptions up to 1 MW (later increased to 5 MWs). The latest regulatory framework related to captive power was developed for rooftop solar projects up to 10 kW. The off-grid captive power sector has never been regulated in Turkey, with the exception of safety standards. The investors are free to install off-grid systems as long as the generation is not connected to the grid to ensure there is no injection of power to the distribution or transmission system. In most cases, special circuit breakers are utilized to enable switching from captive generation to on-grid consumption and vice versa.

Autoproducers and Autoproducer Groups

The regulation which enabled the existence of the autoproducers dates back to1985, and was amended in 1996, 1998, and 2000. Over the years, through these amendments, conditions have improved for the investors. Most prominently, the price for surplus energy was increased from 65% to 85% of the final electricity sales price to consumers (including the network charges). During this period, the main motivations for investing in autoproducers were the ease of permitting and registration, as well as the increased reliability during frequent power outages. The autoproducers were primarily big industrial consumers, some of which were also benefiting from the cogeneration of electricity and heat for their industrial process.

In 2001, Turkey initiated a substantial reform process in its electricity sector for liberalization and privatization and introduced generation licenses, but kept the autoproducer implementation and issued specific licenses to these captive generators. The limit for surplus energy that can be sold was set at 20% of annual generation capacity (MWh) incorporated into the autoproducer license and the Energy Market Regulatory Authority (EMRA) was authorized to increase this to 30% if the system was in need of the energy. Autoproducers were also allowed to supply electricity to other companies who held their shares (as little as one share) and in this situation they were named as autoproducer groups. The amount of energy consumed by group companies in the case of autoproducer groups was excluded from the calculation of the surplus energy limit. Also, this amount was not considered the sale of energy, and was exempt from taxes and fees as a way to promote captive generation.

After the 2001 market reform, the sale of surplus energy was possible through bilateral agreements with large consumers above the eligibility limit defined for retail market opening rather than a regulated price. In case of injecting energy without a consumer or in excess of the consumers’ actual consumption, which can be defined as positive imbalance, there was initially no payment to generators. Starting from 2004 an imbalance pricing mechanism was constituted and positive imbalances were priced at around 25% of negative imbalance price, in order to deter imbalances. Through a change in the Electricity Market Law, EMRA was enabled to increase the surplus energy sale limit as it deems necessary - and the 30% cap was removed. In 2013, the autoproducers were issued generation licenses and the limitation on the sale of surplus energy was removed altogether.

License Exemptions for Renewable Generation up to 1 MW
In 2013, with the new electricity market law, the renewable energy generators up to 1 MW were exempted from licensing requirements, and were also given preferential network connection conditions within the predefined transformer capacities suitable for intermitted generation. This connection capacity limit was initially set at five percent of the transformer capacity, and afterwards redefined for each transformer using a series of technical calculations. Self-consumption was a prerequisite, but there was no minimum self-consumption percentage defined in the regulations, which led to a minimal amount of self-consumption since the price for excess energy was set up to be equal to the feed-in tariff for renewables for the first 10 years of operation, which was set to be higher than the market prices. The license exemption limit for renewables was increased to 5 MW in May 2019.

(Rooftop) Solar Projects up to 10 kW
A comprehensive regulation regarding the solar systems up to 10 kW, which are generally referred to as rooftop solar systems, was enacted in January 2018. These systems are exempt from licensing. Self-consumption is a prerequisite for rooftop solar projects and the connection capacity cannot exceed the capacity contracted for the consumption. The connection applications are handled by the related distribution company and projects less than three kW has to be connected as long as the project fulfills technical standards, while for projects larger than three kW the transformer capacity availability is a prerequisite. Rooftop solar projects have to install two-way meters, and until May 2019 excess energy was calculated hourly and priced at the renewable feed-in tariff rate, which is higher than the retail energy tariff.

After May 2019, the pricing mechanism has been converted to monthly net metering and the excess energy is now purchased by the system using the retail energy tariff excluding network charges and other taxes and fees. The changes in May 2019 also provided exemptions from tax codes for billing excess energy for "household" rooftop solar producers. As a result of the changes in regulation and especially the tax code exemption, the project development phase became easier whereas financial feasibilities of projects have decreased due to the change in pricing of excess electricity generation.

Conclusion
The regulation of captive power in Turkey has evolved over time, initially narrow in scope and gradually expanding, in response to the practical needs of the system, which include:

- self-consumption requirements;
- the pricing of excess energy; and
- connection conditions and fees were adjusted in time as the legislator or the regulator deemed necessary.

4. Conclusion

There are countless motivations compelling regulators to incentivize the development of DER/captive power markets, including adequacy of supply, energy savings, improved reliability of power supply, technological advancement, energy independence, more environmentally conscious generation sources, and reduced exposure to electricity tariff fluctuations. As Rwanda moves forward with a unified regulatory approach to national captive power system implementation and regulation, RURA should draw from international best practices and examples of captive power and DER regulation.

Given the relatively unique nature of captive power regulation and implementation challenges exhibited in other countries, RURA has the opportunity to create a policy initiative of regulatory goals and actions required to comprehensively address captive power system regulation, and include a detailed timeline for executing the specified policy objectives. Captive power projects can be supported and well-maintained through thoughtful regulation with flexible inclusions reflective of the evolving nature of captive power technologies and capabilities. Additionally, it is recommended that RURA craft a captive power regulation designed to provide investors and developers with perceived regulatory certainty and assurance that their investments are safe.

Blueprints for Captive Power Adoption Plans

There is no standard method for developing a captive power adoption plan, as such plans should be tailored specifically for the respective regulatory landscape and grid service territory they apply to. The utility regulator can prepare a plan akin to that of the CPUC and its "DER Action Plan,"[63] or governments can adopt a multi-agency plan. While all captive power adoption plans are inherently different, it is clear that certain elements should unequivocally be included in Rwanda's adoption plan:

1. *Captive Power in Rwanda: Current Developments & Challenges*

Commercial / Industrial and residential customers alike are increasingly interested in installing relatively large (above 50kW) solar panels or generating systems, mainly to reduce their electricity bills or power their operations in Rwanda. Falling panel prices and high tariffs are shortening the payback period on DG investments, creating an attractive value proposition to potential DG/captive power customers. Among the various types of DER, rooftop solar will likely be the most widely adopted in the immediate future. While DER exhibits strong potential to deliver benefits to customers and utilities, it also entails a new set of challenges. Without regulatory frameworks governing its increased implementation in Rwanda, increasing solar penetration or other power generation can pose threats to conventional grid operations through the following effects:

- As customers install more solar panels on their roofs, they will draw less electricity from the grid. Depending on the system generation adequacy level, this can help the system by providing a solution to energy deficits, or hurt the system by reducing the viability of the traditional generators that provide electricity and reliability services.

- At the distribution level, on-grid captive generation can result in technical challenges due to the two-way electricity flow and the intermittent nature of solar power. At the same time, advanced control capabilities of DERs offer potential opportunities for improving electric system reliability by transforming DERs from a passive "do no harm" resource to an active "support reliability" resource when applied in a planned and well-thought-out manner.[64]

- The system operator may not be fully aware of where off-grid solar panels (or other forms of DER) are, the size of their output, and how the output changes during the day. In case of on-grid captive power, system operator should acquire this information during connection application and use it during system operations.

[63] "DER Action Plan." California Public Utilities Commission. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/ Organization/Commissioners/Michael_J._Picker/2016%20DER%20Action%20Plan%20FINAL.pdf

[64] "Impact of Distributed Energy Resources on Bulk Power System." Argonne National Laboratory. https://publications.anl.gov/anlpubs/2017/12/140856.pdf

- Sudden changes to output caused by various weather events can have negative impacts on the system operator's efforts to maintain network stability at all times.

RURA could develop a regulatory framework assessing beyond solar technologies, enabling captive power to create new value propositions for all customers. This foresight will prepare Rwanda well for the future of the grid.

2. *The future of DER in Rwanda*

With DER technology advancing and associated costs continuing to fall customers will likely desire greater involvement in how they source and consume electricity. Given the challenges that DER currently presents, Rwanda's captive power adoption plan should establish the vision for Rwanda's energy future, including a vision for rooftop panels that have already been installed. Given the difficulty of predicting the timing and extent of future technological advances, the adoption plan should be flexibly designed to accommodate new emerging technologies, allowing the market to decide which technologies prevail. The vision can embody a set of principles designed to guide Rwanda for adoption of future DER technologies. For example, these principles may include:

- *Value of DER*: values delivered through DER may include savings on grid maintenance, ensuring reliable power for customers, and avoiding expensive investments in grid infrastructure[65]. For new technologies coming online, the regulator should determine which values they provide to customers in the Rwandan context.
    - The regulator will have a data collection plan to ensure that the necessary data is collected in order to develop and improve value evaluation tools and frameworks.
    - The regulator will have a framework to evaluate the benefits earned from DER in the Rwandan context.
    - Rules and regulations pertaining to DER will be designed to maximize the benefits and minimize possible adversarial effects.

- *System Reliability*: The case of rooftop solar has already exposed some of the system's weaknesses, which signify what to work on.
    - The regulator and utility (which is also the system operator in the Rwandan context) will have greater visibility of where DER systems are located within the grid.
    - The utility will incorporate DER in its operation plans.
    - The regulator will prepare standards for new DER technologies and equipment (e.g. inverters) to avoid reliability conflicts.
    - The utility's investment plan will include infrastructural and training/operations investments needed to accommodate more DER in the grid.

- *Customer Protection*: Customers will be offered increasingly more technology and business model choices. The regulator should prepare plans to protect customers amid the potential flood of true and false information.
    - Customers will have access to their consumption data in order to make informed decisions regarding whether to acquire DER such as rooftop solar. Their data should be also be adequately protected.
    - Whenever the regulator approves new technologies or new business models, there will also be a plan to adequately protect customers from fraud, malpractice, etc.

[65] "Valuing Distributed Energy Resources: A California Update." NRDC Blog. https://www.nrdc.org/experts/valuing-distributed-energy-resources-california-update

- *Tariff considerations*: In the era of DER, customers will want to reduce their electricity bills by harnessing the advantages of new technologies - but the grid must function properly, and the utility should be able to recoup its investments.
    - Tariffs will be more reflective of the true costs of providing utility services, determined through cost of service studies (COSS) and "cost-reflective tariffs."
    - Tariffs will act as a signal to customers to incentivize efficient electricity usage given the change in load profile - and will eliminate cross-subsidies that potentially shift costs to customers without DER.
    - To accurately and fairly compensate transactions for two-way electricity flows, there will be a methodology for valuing the services that DER provides.

As RURA determines the answers to each step and what they entail, RURA can decide on how to proceed regarding next steps towards formulating a captive power regulation in Rwanda. Relative policy and technical circumstances are specific to each country; this heightens the importance of evaluating these steps before establishing next steps in Rwanda's regulatory approach. In general, any country interested in promoting a captive power framework should assess the following foundational planning and regulatory steps:

- Identify stakeholders who are interested in developing these installations - and discuss their regulatory and technical requirements and needs.
- Identify large consumers who would benefit from captive power.
- Identify thresholds for self-consumption requirement, capacity limits for licensing or registration regimes.
- Identify connection requirements to the system and related system connection and use fees.
- Determine the role of system operators in the process.
- Analyze whether it is necessary to adopt an explicit regulation for captive power, or if the rules will be governed through different regulations.
- Based on policy objectives identify which technologies (renewables, cogeneration) will be promoted for captive power in the short-term and long-term.
    - Renewable goals
    - Energy efficiency objectives
- Analyze effects of captive generation on the power system.
- Analyze and identify the appropriate pricing mechanism for excess electricity:
    - feed-in tariff;
    - full retail rate;
    - retail energy rate (excluding network tariffs, taxes and fees);
    - free market price; and
    - net metering.
- Determine the allowable purposes for using captive power (commercial, et cetera).
- Determine if pilot projects are a priority for proof of concept, before adopting specific regulations on captive power.

Comprehensive Captive Power Adoption Planning in Rwanda

Rwanda's comprehensive captive power adoption plan and accompanying regulatory framework should provide a long term vision of what Rwanda's grid will resemble when solar PV and other DER are increasingly integrated into the grid, and present concrete regulatory steps required in order to facilitate and achieve that vision. Preparing a comprehensive captive power adoption plan and accompanying regulatory framework will allow Rwanda to tackle the immediate changes resulting from and required by increased adaption of DER - and plan well into the future, as DER technological advancement will span across countless innovative technologies beyond present captive power generation methods.

New technologies and new business models sharing common characteristics will continue to appear; such defining characteristics will reflect customer (or a third party other than the utility)-owned infrastructure, two-way flow of electricity, pressure for lower energy costs, and many others. While it is impossible to know what the future DER technologies will look like, it is pragmatic and highly recommended to prepare a comprehensive national plan to coordinate many individual DER systems so that in aggregation, customers can participate in the provision of reliability and market services that are beneficial to the grid.

Although rooftop solar and other forms of DER may, in the short term, appear to challenge grid stability and financial viability of the utility, developing mechanisms allowing DER (and captive power) to provide various services to the grid will in time introduce new value streams for customers, foster a more diversified and resilient grid, provide increased adequacy of supply, contribute to environmentally-conscious initiatives in the power sector, and ultimately contribute to lower system costs in the long run.

Preparing an adoption plan will require cooperation between related parties (the regulator, utility, system operator, consumer groups, and other stakeholders) because all parties foresee challenges for DER. For example, utilities may face large numbers of interconnection requests, distributed generation on some circuits will exceed the load, and many operating challenges involving feeder voltage regulation, hosting capacity limits, inverter grid support and grounding options will present themselves.[66] Preparing for these technical challenges (and their financial mechanisms and implications among all stakeholders) is of primary importance for RURA moving forward into an increasingly diversified generation layout.

[66] "Power Delivery and Utilization - Distribution and Utilization." EPRI. http://www.epri.com/Our-Portfolio/Pages/Portfolio.aspx?program=067418

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